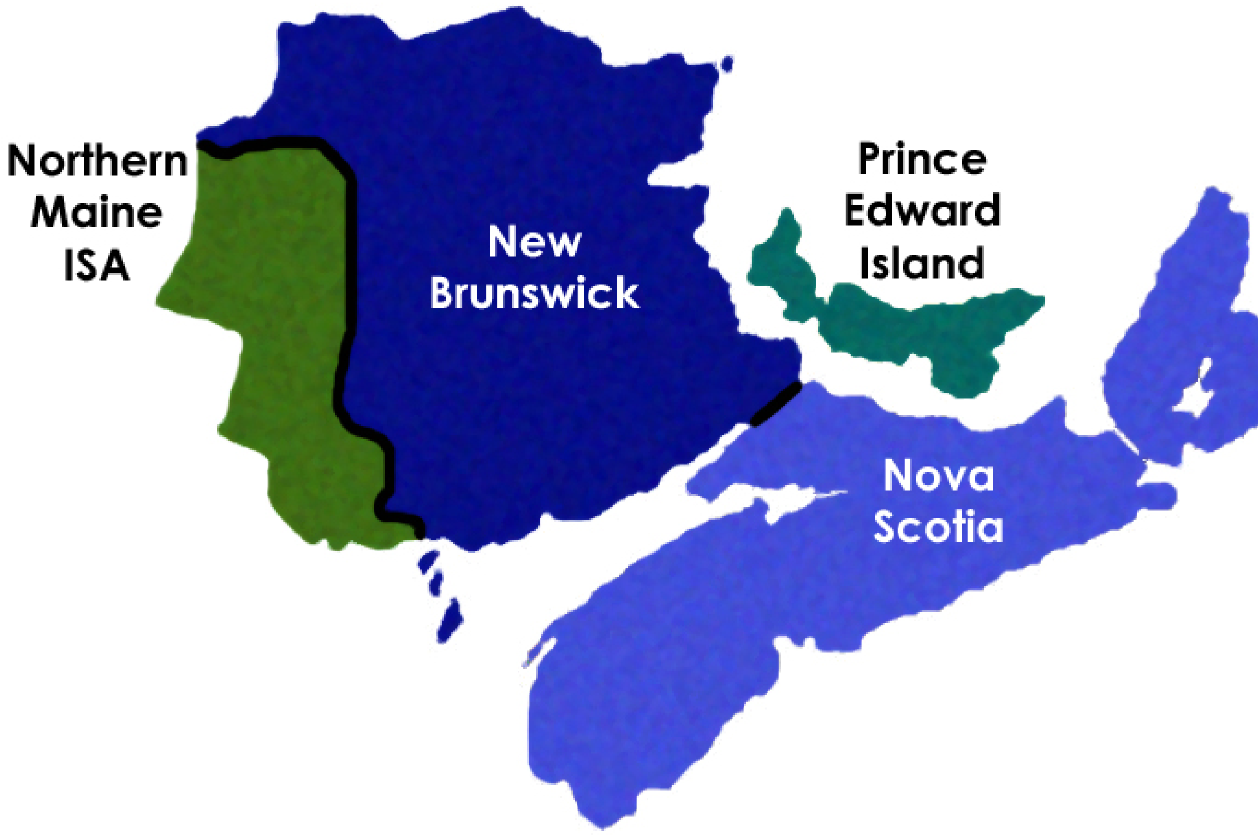
NPCC
2019 MARITIMES AREA
COMPREHENSIVE REVIEW OF RESOURCE ADEQUACY
Approved by the RCC on December 3, 2019



NEW BRUNSWICK POWER CORP.
NOVA SCOTIA POWER INCORPORATED
MARITIME ELECTRIC COMPANY, LIMITED
NORTHERN MAINE ISA, INC.

September 2019

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EXECUTIVE SUMMARY

The 2019 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2020 through December 2024, has been prepared to satisfy the compliance requirements as established by the Northeast Power Coordinating Council (NPCC). The guidelines for this review are specified in the *NPCC Regional Reliability Directory #1 Appendix D (Approved: September 30, 2015)*. This review supplants the previous Comprehensive Review that was performed in 2016 and approved by the RCC on December 6, 2016.

The NPCC resource adequacy criterion of a Loss of Load Expectation (LOLE) of not more than 0.1 days per year of firm load disconnections is not exceeded by the Maritimes Area for all years covered by this review, and varies between 0.008 to 0.010 days/year for the base case forecast. The Maritimes Area is also shown to adhere to its own 20% reserve criterion in all years covered by this review, with minimum reserve levels varying between 30% and 35% for the base case forecast.

Sensitivity analyses were performed to determine the LOLE effects of high load growth, zero wind generation, and removing all external tie benefits. The Maritimes Area is shown to meet the NPCC resource adequacy criterion in all years for each of these sensitivities.

Table 1 provides a summary of the major assumptions of this review.

Table 1: Summary of Major Assumptions and Results

MAJOR ASSUMPTIONS	
Load Forecast	2019
Load and Wind Shape	2017
Resource Adequacy Criterion	Loss of Load Expectation not more than 0.1 days/year
Maritimes Criterion Reserve	20% of peak firm load
Interconnection Benefits	300 MW
Area Purchases/Sales (June through May yearly)	Firm Sales: 2019/20 110 MW 2020/21 69 MW 2021/22 66 MW 2022/23 149 MW 2023/24 0 MW No Firm Purchases were assumed in any year.
Maritime Link Project	Mid-2020: 153 MW of purchases from Newfoundland and Labrador to Nova Scotia will offset planned retirement of a 148 MW Nova Scotia generator

Table 2 provides a complete summary of LOLE results, including the base case and each of the sensitivities performed for this review.

Table 2: Summary of LOLE Results

Year	Base Case LOLE	High Load Growth LOLE	Zero Wind LOLE	No Tie Benefits LOLE
	days/year	days/year	days/year	days/year
2020	0.010	0.010	0.070	0.029
2021	0.008	0.012	0.060	0.014
2022	0.009	0.016	0.065	0.016
2023	0.010	0.023	0.068	0.021
2024	0.009	0.037	0.065	0.012

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1.0 INTRODUCTION

The 2019 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2020 through December 2024, has been prepared to satisfy the compliance requirements as established by the Northeast Power Coordinating Council (NPCC). The guidelines for this review are specified in *NPCC Directory #1 Appendix D, Guidelines for Area Review of Resource Adequacy (Approved: September 30, 2015)*. This review supplants the previous Comprehensive Review that was performed in 2016 and approved by the RCC on December 6, 2016.

The Maritimes Area is a winter peaking area with separate jurisdictions and regulators in New Brunswick, Nova Scotia, Prince Edward Island (PEI), and Northern Maine. New Brunswick Power (NB Power) is the Reliability Coordinator for the Maritimes Area.

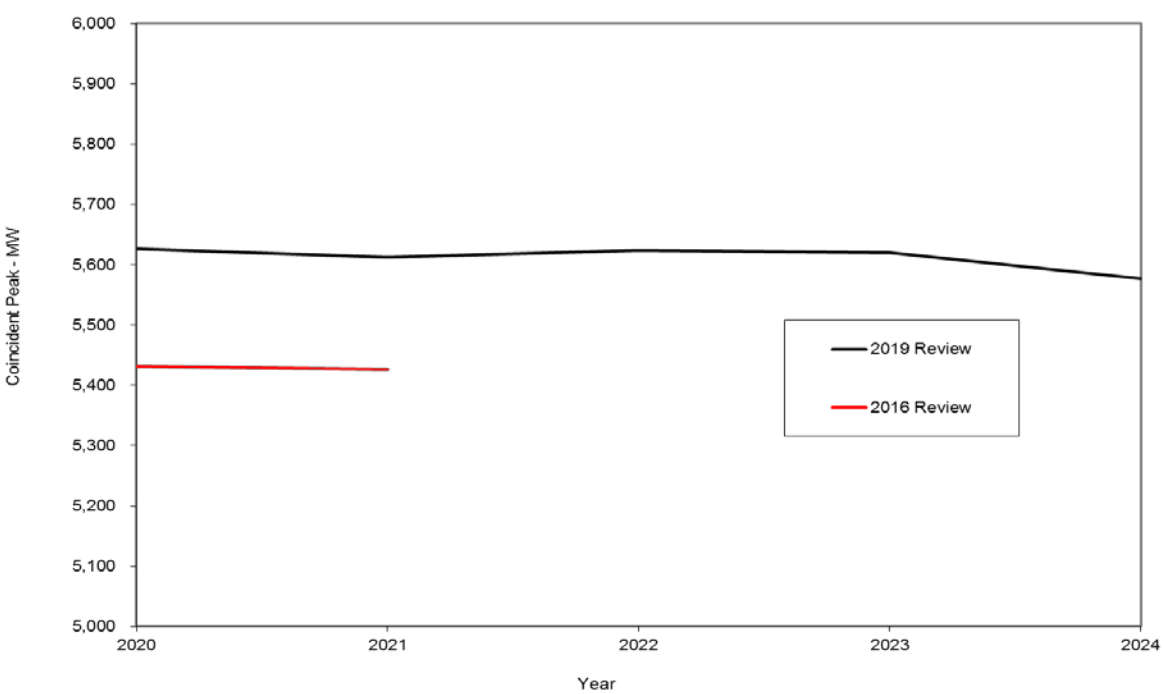
Table 3 provides a comparison of the load and resource forecasts in the 2019 and 2016 reviews. The coincident peak demand forecast for 2020 is 5,626 MW, which is 194 MW above the 5,432 MW forecast in the 2016 Comprehensive Review. This increased peak demand forecast reflects increases in electric heating demands which were not offset by declines in industrial loads and demand shifting programs. Demand shifting and energy efficiency programs are expected to reduce peak demand in the Maritimes Area by 72 MW to 317 MW during the Comprehensive Review period. The average annual demand growth over the period of this review is -0.22%, which is marginally lower than the 0.16% average demand growth forecast in the 2016 review but still essentially flat. A comparison of load forecasts is shown in Figure 1.

In addition to installed capacity, the resource forecast included in Table 3 incorporates external purchases and/or sales (as additions or reductions to the forecast respectively), tie benefits from neighbouring utilities, and projections of on-peak wind production (reflecting both capacity changes as well as a 2017 wind shape for this 2019 review versus a fiscal year 2011/12 and a fiscal year 2011/12 wind shape for the 2016 review).

Table 3: Comparison of Load and Resource Forecasts

Winter Peak (Month of January)	2019 Review Load MW	2016 Review Load MW	2019 Review Resources MW	2016 Review Resources MW
2020	5,626	5,432	6,927	7,454
2021	5,612	5,426	7,078	7,454
2022	5,623	N/A	7,055	N/A
2023	5,620	N/A	6,990	N/A
2024	5,577	N/A	7,139	N/A
Five Year Period	**2020–2024**	**2017–2021**		
Annual Average Growth Rate	-0.22%	0.16%		

Figure 1: Comparison of Load Forecasts



2.0 RESOURCE ADEQUACY CRITERION

2.1 Statement of Resource Adequacy Criterion

For planning purposes, New Brunswick, Nova Scotia, PEI and Northern Maine individually apply a capacity based reserve criterion in determining their required reserves.

New Brunswick, Nova Scotia, and Northern Maine each plan for a reserve equal to the greater of the capacity of the largest generator or 20% of the firm load. For this review, the latter criterion was applicable in all years. PEI plans for a reserve equal to 15% of its firm load. As a simplification, this review applies the 20% reserve criterion to the Maritimes Area as a whole because of the relatively small size of PEI compared to the rest of the Maritimes Area. Thermal and hydro generators are considered available at the Dependable Maximum Net Capability (DMNC) in the determination of the reserve margin.

The NPCC resource adequacy criterion (from *NPCC Directory #1 Design and Operation of the Bulk Power System, Requirement 4 (Dated: September 30, 2015*) states:

> "**R4** Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year.
>
> **R4.1** Make due allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

2.2 Emergency Operating Procedures

Although this document presents a review of resource adequacy for the interconnected Maritimes Area, each separate jurisdiction remains under the exclusive control of its system operator for economic dispatch. For reliability purposes, however, reserve sharing agreements do exist and the separate systems operate within a common Reliability Coordinator area in accordance with NERC and NPCC criteria and guidelines.

Actions taken by the Energy Coordinator/Dispatcher, when faced with a developing or sudden capacity shortage, are based upon a number of possible actions best suited to the prevailing system conditions. In practice, the corrective actions taken are one or more of the following Emergency Operation Procedures (EOP):

1. Synchronize and load all available hydro generators.
2. Bring on-line generators up to their DMNC.
3. Cancel economy and other external interruptible sales.
4. Begin start-up procedures for "cold-standby" thermal generators.
5. Synchronize and load combustion turbines.
6. Purchase capacity from Hydro-Québec.
7. Purchase capacity from New England.
8. Cut interruptible sales to industrial customers (See Table A-1).
9. Maximize MVAR support (capacitor banks, synchronous condensers) if capacity shortage is causing a low voltage condition in a particular area.
10. Implement a 5% voltage reduction at selected substations within Nova Scotia (1–5 MW)
11. Appeal to the public for voluntary customer load reduction.
12. Disconnect customer loads as necessary to correct either a local or widespread problem.

Some or all of the above steps may be used in varying sequence to meet a capacity shortage depending on the generation pattern in effect at the time and whether or not the shortage results in localized internal system problems.

Although steps 10 and 11 are valid, the level of assistance available from these procedures is not modeled in this study.

2.3 Maritimes Area Reserve Criterion

The Maritimes Area employs a reserve criterion of 20% of firm load. The required installed reserve is shown in Section 3.1.

2.4 Relationship of Maritimes Reserve Criterion to NPCC Reliability Criterion

To relate the Maritimes Area reserve criterion of 20% to the NPCC resource adequacy criterion as stated in Section 2.1, LOLE was evaluated with the Maritimes Area firm load scaled so that the reserve was equal to 20%. The results showed that a Maritimes Area reserve of 20% corresponds to an LOLE of approximately 0.052 days per year. At this load level, only about 130 MW of additional load was required to match the NPCC LOLE resource adequacy criterion of 0.1 days per year.

The preceding demonstrates that the 20% Maritimes Area reserve criterion correlates closely with the 0.1 days/year NPCC LOLE resource adequacy criterion.

2.5 Recent Reliability Studies

Resource Planners in New Brunswick, Nova Scotia, PEI, and Northern Maine individually conduct internal reviews of their capacity requirements by comparison of generation sources with forecast loads according to the reserve criterion described previously.

The results presented in this review are based upon an evaluation conducted during the second and third quarters of 2019 for the period 2020 through 2024. This review supplants the previous Comprehensive Review that was performed in 2016 and approved by the RCC on December 6, 2016. Interim reviews of resource adequacy for the Maritimes Area were completed in the years 2017 and 2018 covering the years 2018–2021 and 2019–2021 respectively. The results of this 2019 comprehensive review are consistent with these two interim reviews showing the Maritimes Area complying with the NPCC resource adequacy criterion for all years.

2.6 Load Forecast Uncertainty

To determine load forecast uncertainty (LFU) an analysis of the historical load forecasts of the Maritimes Area utilities has shown that the standard deviation of the load forecast errors is approximately 4.6% based upon the four year lead time required to add new resources. To incorporate LFU, two additional load models were created from the base load forecast by increasing it by 4.6 and 9.2 percent (one or two standard deviations) respectively. The reliability analysis was repeated for these two load models.

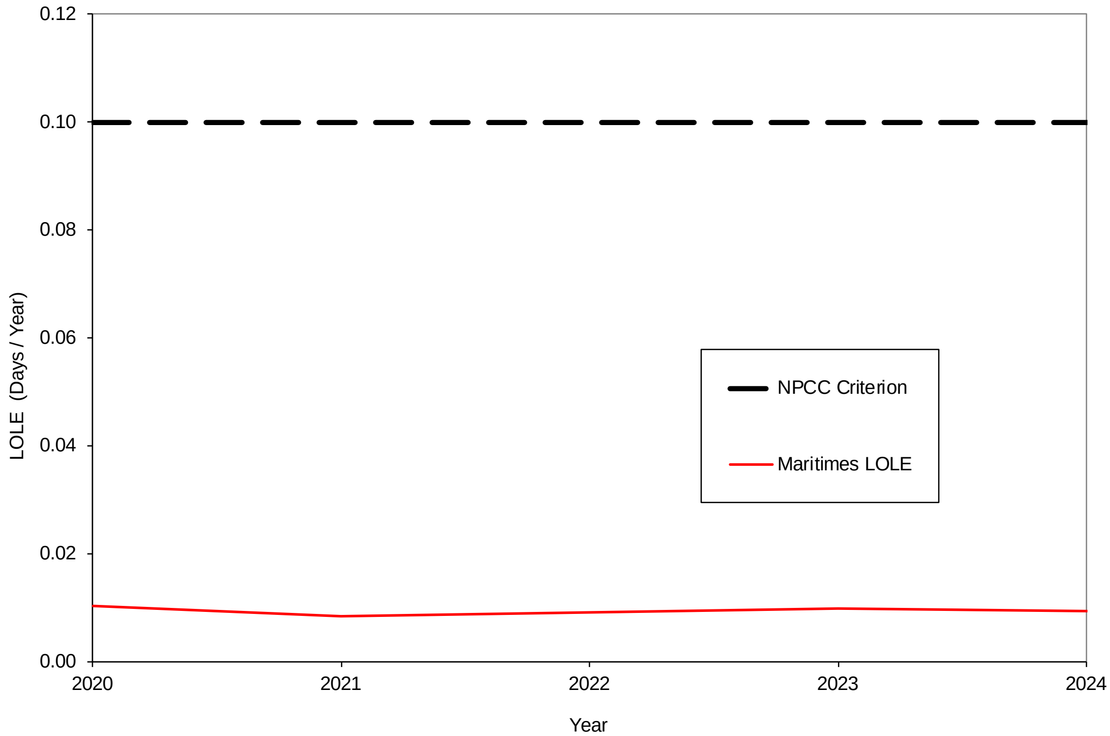
It is assumed that the forecast error is approximately normally distributed around the forecast value and that the contribution to system LOLE is negligible when loads are less than the forecast value by more than ½ a standard deviation. These assumptions result in weighting factors of 0.383, 0.242, and 0.067 for the three results obtained using the base, 4.6 percent increased, and 9.2 percent increased load models respectively.

The LOLE analysis of the base case, including the impacts of LFU, as shown in Table 4 and Figure 2 demonstrates that the Maritimes Area system meets the NPCC resource adequacy criterion of no more than 0.1 days/year from 2020 to 2024.

Table 4: LOLE days/year – Base Case with Load Forecast Uncertainty

Calendar Year	Expected Number of Firm Load Disconnections days/year
2020	0.010
2021	0.008
2022	0.009
2023	0.010
2024	0.009

Figure 2: LOLE (days/year) – Base Case with Load Forecast Uncertainty



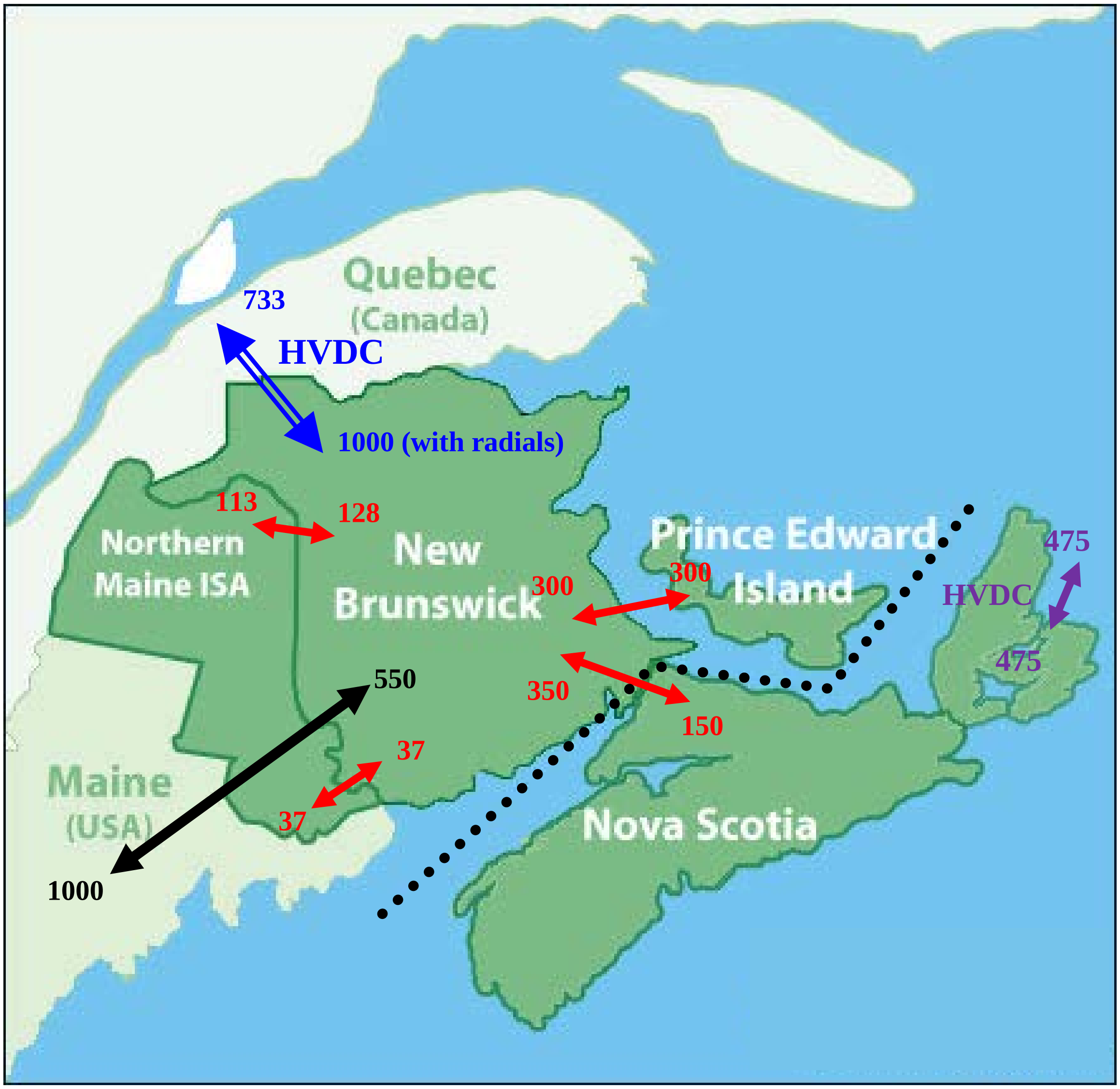
2.7 Intra-Area Transmission Capacity Limits

Within the Maritimes Area, the areas of Nova Scotia, PEI, and Northern Maine are each connected only to New Brunswick as per Figure 3. A transmission congestion issue of consequence to the LOLE occurs for only one of these three interconnections, the tie between New Brunswick and Nova Scotia.

Transmission capacity limits between Northern Maine and New Brunswick were not modeled for this analysis. These normal limits are a result of parallel operation of four lines (two 138 kV, two 69 kV) that Northern Maine keeps below thermal ratings to ensure that the trip of one of these lines doesn't overload the others. Should one or more contingencies occur in Northern Maine, the lines can be switched from parallel to radial operating modes. This effectively allows a high enough transfer limit from New Brunswick to meet the peak load in Northern Maine.

Late in 2017, PEI installed two additional undersea cables between New Brunswick and PEI. Based on a tripling of cable capacity and two additional parallel paths, the single cable contingency limiting flows from NB to PEI was eliminated. For this review, the transmission limit for this path was increased from 222 MW to 300 MW.

Figure 3: Maritimes Area Transmission Capacity Limits



3.0 RESOURCE ADEQUACY ASSESSMENT

3.1 Comparison of Forecast and Required Reserve – Base Case

In the comparison of the forecast and required reserve, the following definitions apply. The required reserve of 20% is the reserve criterion used for the Maritimes Area. The forecast reserve is the actual reserve that will occur during the peak load hour for each year.

Table 5 represents the results of the reserve comparison using the hourly coincident peak load forecast for the Maritimes Area. The corresponding capacity values incorporate all known firm sales and purchases with external neighbouring Areas, modeling wind generation production using 2017 wind shapes from each Maritimes Area sub-area. In each year of the analysis, both the forecast and minimum reserves are greater than the required reserve.

Table 5: Forecast, Minimum, and Required Reserve Levels – Base Case

Month of January	Forecast* Capacity	Peak Load	Inter. Load	Forecast Reserve		Minimum Hourly Reserve		Required Reserve	
	MW	MW	MW	MW	%	MW	%	MW	%
2020	6,927	5,626	270	1,571	29	1,559	29	1,071	20
2021	7,078	5,612	277	1,743	33	1,728	33	1,067	20
2022	7,055	5,623	277	1,709	32	1,692	32	1,069	20
2023	6,990	5,620	277	1,647	31	1,635	31	1,069	20
2024	7,139	5,577	277	1,839	35	1,822	35	1,060	20

* Forecast capacity incorporates all known firm purchases/sales with neighbouring Areas, and also includes forecast wind generation production coincident with the peak load.

$$\text{Forecast Reserve (\%)} = \left[\frac{\text{Forecast Capacity} - (\text{Peak Load} - \text{Inter. Load})}{(\text{Peak Load} - \text{Inter. Load})}\right] * 100\%$$

$$\text{Minimum Reserve (\%)} = \frac{\text{Min. of Hourly } [\text{Capacity} - (\text{Load} - \text{Inter. Load})]}{(\text{Load} - \text{Inter. Load})} * 100\%$$

3.2 LOLE results – High Load Growth

Table 6 and Figure 4 illustrate LOLE results if the average annual growth rate is 1% higher than forecast (i.e. +0.78% per year versus -0.22%per year compounded over the four year period of this review). The results show that the NPCC resource adequacy criterion is met in all years.

Table 6: Loads and LOLE Results – High Load Growth

Month of January	High Load Growth Load	Base Case Load	Difference	High Load Growth LOLE	Base Case LOLE
	MW	MW	MW	days/year	days/year
2020	5,626	5,626	0	0.010	0.010
2021	5,670	5,612	58	0.012	0.008
2022	5,714	5,623	91	0.016	0.009
2023	5,759	5,620	139	0.023	0.010
2024	5,804	5,577	227	0.037	0.009

3.3 LOLE Results – Zero Wind

The Maritimes Area models forecast wind generation production on an hourly basis for its LOLE and reserve calculations. Simulated wind capacity during the Maritimes coincident peak demand* rose from 324 MW in 2020 to 343 MW by 2022 with no further wind generation additions beyond that time. A sensitivity analysis was performed with the wind capacity on the system set to zero output for all hours. Table 7 and Figure 4 illustrate LOLE results for the zero wind generation scenarios. The results show that Maritimes Area is not reliant on wind capacity to meet the NPCC resource adequacy criterion.

Table 7: Capacity and LOLE Results – Zero Wind

Month of January	Zero Wind Capacity	Base Case Capacity	Difference	Zero Wind Capacity LOLE	Base Case LOLE
	MW	MW	MW	days/year	days/year
2020	6,602	6,927	-325	0.070	0.010
2021	6,747	7,084	-337	0.060	0.008
2022	6,712	7,055	-343	0.065	0.009
2023	6,647	6,990	-343	0.068	0.010
2024	6,796	7,139	-343	0.065	0.009

* The on peak wind generation values do not represent the effective load carrying capability or capacity value of the wind resources due to the variability of wind from hour to hour in the wind shape used.

3.4 LOLE Results – No Tie Benefits

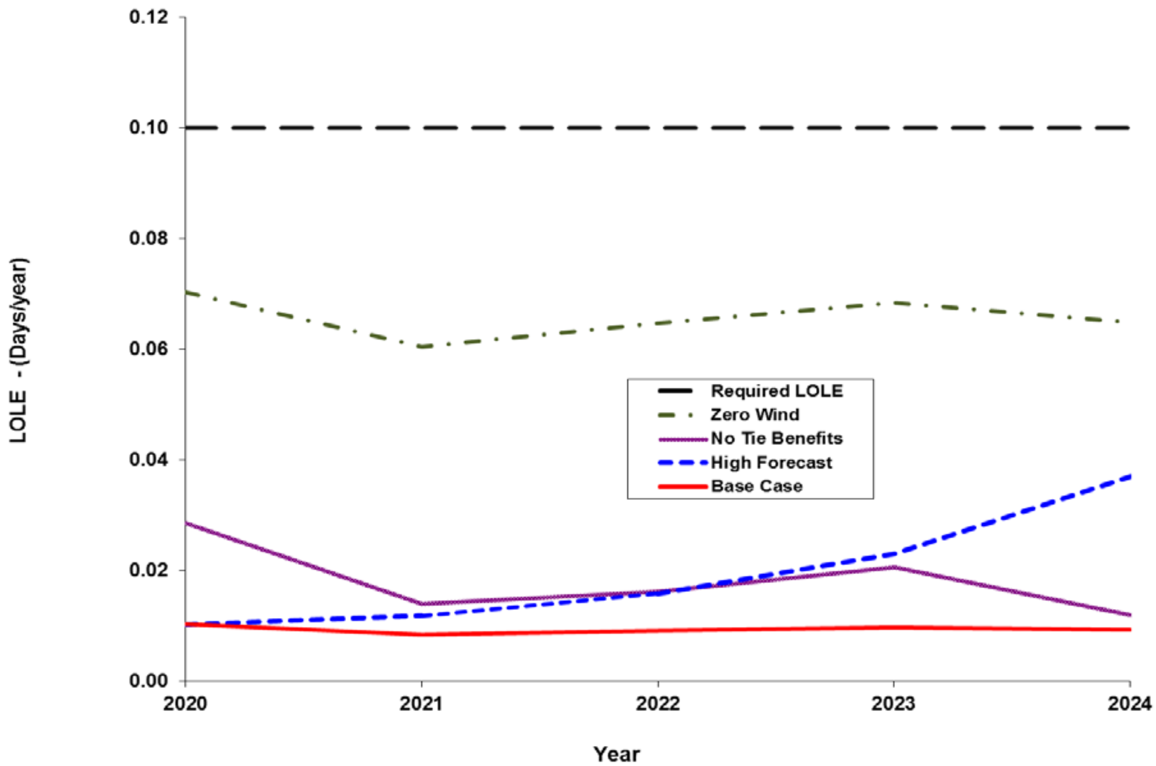
Since 2011, NB Power has assumed 300 MW of tie benefits in its resource adequacy assessments. These tie benefits are based on a 2011 decision by the New Brunswick Market Advisory Committee to recognize the lowest historical Firm Transmission Capacity posted from summer peaking New England to winter peaking New Brunswick since the commissioning of the second 345 kV tie between these systems in December 2007. To the extent that future capacity purchases from New England to New Brunswick occur across this interface, these tie benefits will be reduced accordingly. Tie benefits from other neighbouring jurisdictions have not been considered since they also experience peak loads in winter.

In the CP-8 report *Review of Interconnection Assistance Reliability Benefits (December 31, 2015, Approved by RCC March 2, 2016)* the "As Is" scenario estimated tie benefit potential for the Maritimes Area to be 702 MW and 1,012 MW for the years 2016 and 2020 with an export of 200 MW modeled in both test years. Based on this study, the 300 MW of tie benefits assumed for this 2019 Comprehensive Review is conservative. A sensitivity analysis performed for this review shows that the Area does not require interconnection assistance to meet the NPCC resource adequacy criterion. The results are shown in Table 8 and Figure 4.

Table 8: Capacity and LOLE Results – No Tie Benefits

Month of January	No Tie Benefits Capacity	Base Case Capacity	Difference	No Tie Benefits LOLE	Base Case LOLE
	MW	MW	MW	days/year	days/year
2020	6,627	6,927	-300	0.029	0.010
2021	6,778	7,078	-300	0.014	0.008
2022	6,755	7,055	-300	0.016	0.009
2023	6,690	6,990	-300	0.021	0.010
2024	6,839	7,139	-300	0.012	0.009

Figure 4: LOLE Results – All Base and Sensitivity Cases



3.5 Contingency Plans

The Maritimes Area utilities' forecast high and low load growth scenarios, and their impact on the generation dispatch is continually being evaluated to address load and resource uncertainties. In the event of a higher than expected growth in load, a number of options would be considered. These options include the purchases of capacity and/or energy, the advancement of base load generation additions, and the installation of combustion turbines.

4.0 FORECAST RESOURCE CAPACITY MIX

Installed wind of 1169 MW in the Maritimes Area expected at the start of 2020 now includes 164 MW of formerly energy only wind capacity that has had transmission restrictions removed and is now considered as available capacity. During 2020 and 2021 a further 60 MW of wind generation will be installed in the Maritimes Area.

The only other capacity addition in the area during the period is the expected installation of an 18 MW diesel fueled generator in 2023.

4.1 Forecast Resource Capacity Mix

Table 9 and Figure 5 illustrate the forecast resource capacity mix for the Maritimes Area. Appendix A, Section 1.2, Table A-2 presents a detailed list of all capacity resources for the Maritimes Area.

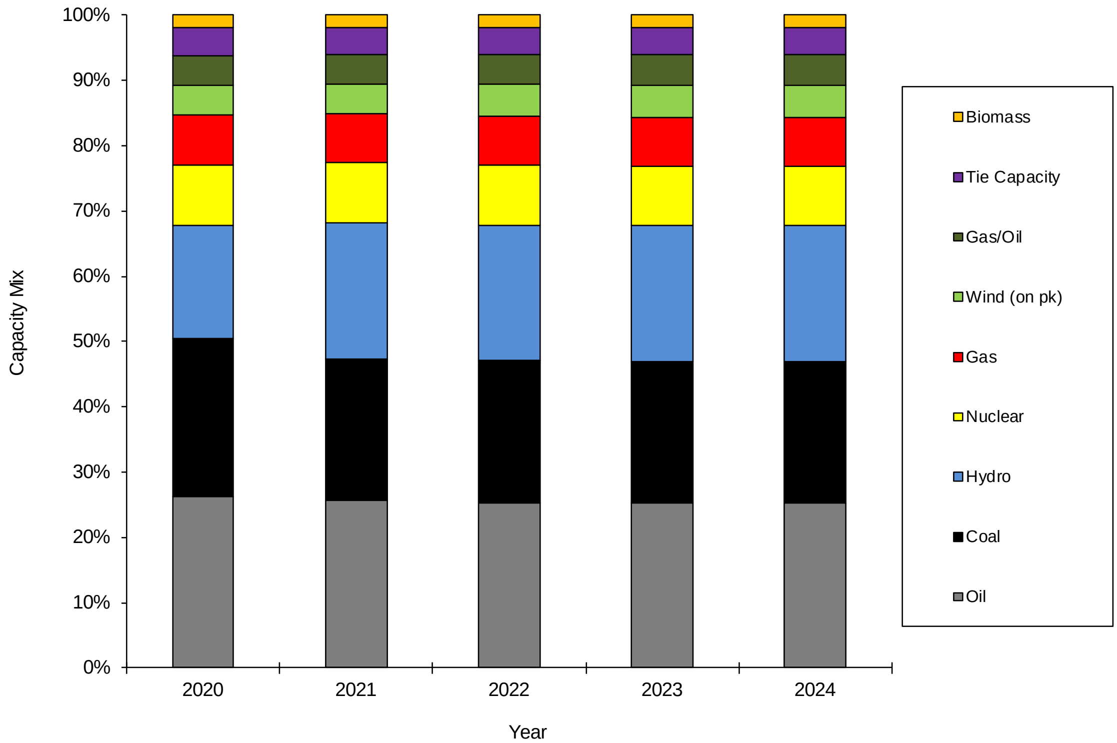
Table 9: Forecast Capacity Resource Mix

Month of January	Oil	Coal*	Hydro *	Nuclear	Gas	Wind**	Gas/Oil	Tie Benefits	Biomass
	%	%	%	%	%	%	%	%	%
2020	26	24	17	9	8	5	5	4	2
2021	26	22	21	9	7	5	4	4	2
2022	25	22	21	9	7	5	4	4	2
2023	25	22	21	9	7	5	5	4	2
2024	25	22	21	9	7	5	5	4	2

* Coal and Hydro capacity percentages reflect the retirement of a 148 MW coal generator and its replacement by a 153 MW hydro based capacity purchase occurring mid-2020.

** Wind capacity based on forecast wind production during Maritimes coincident peak

Figure 5: Forecast Capacity Resource mix



4.2 Reliability Impact of Resource Diversification Strategy

As can be seen from Table 9 and the associated Figure 5, the Maritimes Area has a diversified mix of resources such that there is not a high degree of reliance upon any one type or source of fuel. This resource diversification also provides flexibility to respond to any future environmental issues, such as potential restrictions to greenhouse gas emissions. The Renewable Energy Standard in Nova Scotia calls for 25% of energy sales to be supplied from renewable resources in 2019 and increases to 40% in 2020. The increase in Nova Scotia renewable requirements in 2020 will largely be met by the import of hydro energy from Newfoundland and Labrador and will result in reduced fossil fuel generation.

APPENDIX A - DESCRIPTION OF RESOURCE RELIABILITY MODEL

DESCRIPTION OF RESOURCE RELIABILITY MODEL

1.0 Load Model

1.1 Calendar year 2017 hourly system load data for the Maritimes Area utilities was used as the load shape for this study. Demand and energy forecasts for 2020 to 2024 inclusive were prepared by each resource planner. The combined load and energy forecasts for the Maritimes Area are shown in Table A-1.

Table A-1: Maritimes Area Load Forecast

COINCIDENT DEMAND MW													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Peak**
2020	5626	5370	4852	4106	3415	3149	3209	3305	3196	3540	4404	5083	5626
2021	5612	5358	4842	4102	3409	3151	3211	3312	3193	3555	4420	5095	5612
2022	5623	5366	4858	4134	3438	3172	3232	3327	3218	3558	4421	5095	5623
2023	5620	5356	4845	4099	3399	3153	3207	3310	3198	3544	4393	5064	5620
2024	5577	5308	4809	4090	3387	3142	3193	3287	3176	3528	4374	5032	5577
ENERGY GWh													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2020	3069	2776	2743	2274	2028	1834	1937	1953	1864	2081	2342	2853	27755
2021	3069	2776	2739	2267	2018	1831	1935	1951	1862	2093	2353	2862	27756
2022	3075	2784	2749	2295	2049	1853	1955	1973	1883	2099	2360	2867	27941
2023	3077	2786	2750	2281	2034	1849	1950	1966	1878	2094	2354	2861	27880
2024	3073	2783	2746	2286	2038	1849	1945	1962	1873	2090	2351	2857	27853
INTERRUPTIBLE DEMAND MW													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	On Peak
2020	270	252	335	339	321	336	355	347	345	336	334	261	270
2021	277	259	344	348	329	345	363	354	353	343	341	269	277
2022	277	259	344	348	329	345	363	354	353	342	341	268	277
2023	277	259	344	347	328	344	363	354	353	342	340	268	277
2024	277	259	343	347	328	344	363	354	353	342	340	268	277

Note: The forecast coincident peak demand occurs in January.

1.2 Load forecast uncertainty (LFU) was considered in the analysis as described in Section 2.6 of the main report.

1.3 Some entities within the Maritimes Area supply a portion of their own electricity demand and energy requirements. Only the portions that are supplied by the Maritimes Area utilities were included in the area forecast.

1.4 The load forecast in Table A-1 includes the impact of DSM and efficiency programs.

2.0 Generator Resource Representation

Generator data for the four members of the Maritimes Area are presented in Table A-2. Table A-3 presents a summary of changes in resource data for the period 2020–2024 inclusive. The following sections document the tabulated data.

2.1 Generator Ratings

2.1.1 Definition

The generator capacity ratings represented in Table A-2 are the Dependable Maximum Net Capability (DMNC) winter ratings. These are evaluated periodically to establish each generator's sustained maximum net output over a two consecutive hour period.

2.1.2 Procedure for Verifying Ratings

With the July 1, 2019 retirements of NPCC directories #9 and #10, testing and verification of transmission and generator facility ratings are governed by NERC reliability standard MOD-025-2, Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability (Attachment 1). This standard establishes the methodologies and performance requirements necessary to ensure generating facilities are tested at least every 5 years to verify they can meet their ratings under operating conditions. A link to this standard is provided here:

NERC Standard MOD-025-2

Table A-2: Maritimes Area Resources

New Brunswick Resources as of January 1, 2020				
Plant	**Unit**	**Type**	**MW Capacity**	**Notes**
Point Lepreau	1	Nuclear	660	
Belledune	2	Coal	466	
Coleson Cove	1	Oil	324	
	2	Oil	324	
	3	Oil	324	
Bayside	6	Natural Gas	290	Capacity (Combined Cycle Operation)
Grand Manan	3	Diesel	28	
Millbank	1	Diesel	99	Summer Capacity = 86MW
	2	Diesel	99	Summer Capacity = 86MW
	3	Diesel	99	Summer Capacity = 86MW
	4	Diesel	99	Summer Capacity = 86MW
Ste Rose	1	Diesel	99	Summer Capacity = 86MW
Grandview	1	Natural Gas	49	
	2	Natural Gas	49	
NUG Purchases		Biomass	38	
		Hydro	15	
Mactaquac	1	Hydro	109	
	2	Hydro	0	109 MW out for maintenance Jan. 2020
	3	Hydro	109	
	4	Hydro	115	
	5	Hydro	112	
	6	Hydro	112	
Beechwood	1	Hydro	36	
	2	Hydro	36	
	3	Hydro	41	
Grand Falls	1	Hydro	16	
	2	Hydro	16	
	3	Hydro	16	
	4	Hydro	16	
Tobique	1	Hydro	10	
	2	Hydro	10	
Nepisiguit Falls	1	Hydro	11	
Sisson	1	Hydro	9	
Milltown	1	Hydro	4	
Small Producers		mostly Hydro	12	
Tie Benefits			300	

NB Wind	All	Wind	104	During Maritime peak (331 MW installed)
TOTAL CAPACITY			4,256	Total Capacity as of January 2020

Table A-2: Maritimes Area Resources (cont'd)

Nova Scotia Resources as of January 1, 2020				
Plant	**Unit**	**Type**	**MW Capacity**	**Notes**
Lingan	1	Coal	153	Summer Capacity = 146 MW
	2	Coal	148	Summer Capacity = 141MW
	3	Coal	153	Summer Capacity = 146 MW
	4	Coal	153	Summer Capacity = 146 MW
Trenton	5	Coal	150	Summer Capacity = 135 MW
	6	Coal	154	Summer Capacity = 115 MW
Pt. Tupper	2	Coal	150	Summer Capacity = 145 MW
Tufts Cove	1	Gas/Oil	78	Summer Capacity = 74 MW
	2	Gas/Oil	93	Summer Capacity = 91 MW
	3	Gas/Oil	147	Summer Capacity = 144 MW
	4	Natural Gas	49	Summer Capacity = 45 MW
	5	Natural Gas	49	Summer capacity = 45 MW
	6	Natural Gas	46	Summer Capacity = 130 MW
Pt. Aconi	1	Coal	168	Summer Capacity = 166 MW
Burnside	1	Lt Oil	33	Summer Capacity = 25 MW
	2	Lt Oil	33	Summer Capacity = 25 MW
	3	Lt Oil	33	Summer Capacity = 25 MW
	4	Lt Oil	33	Summer Capacity = 25 MW
Victoria Junction	1	Lt. Oil	33	Summer Capacity = 25 MW
	2	Lt. Oil	33	Summer Capacity = 25 MW
Tusket	1	Lt. Oil	0	33/25 MW Win/Sum cap out of service
NSIPP1 NUG Purchases	All	Biomass	28	
PH Biomass		Biomass	43	
COMFIT Biomass	All	Biomass	6	
Wreck Cove	1	Hydro	106	
	2	Hydro	106	
Annapolis Tidal		Hydro	4	
Avon 1&2		Hydro	7	
Black River		Hydro	23	
Nictuax		Hydro	8	
Lequille		Hydro	11	
Paradise		Hydro	5	
Mersey		Hydro	43	
Sissiboo		Hydro	24	
Bear River		Hydro	13	
Tusket		Hydro	2	
St. Margrets		Hydro	11	
Sheet Harbour		Hydro	11	
Dickie Brook		Hydro	4	
Fall River		Hydro	1	
NALCOR Firm Contract		Hydro	0	Expected June 1, 2020

NS Wind Projects	All	Wind	135	During Maritime peak (592 MW installed) †
TOTAL CAPACITY			2,480	Total Capacity as of January 2020

† The on peak wind generation value does not represent the effective load carrying capability or capacity value of the wind resources due to the variability of wind from hour to hour in the wind shape used.

Table A-2 Maritimes Area Resources (cont'd)

Prince Edward Island Resources as of January 1, 2020				
Plant	**Unit**	**Type**	**MW Capacity**	**Notes**
Charlottetown	8	Oil	10	
	9	Oil	19	
	10	Oil	19	
	CT3	Diesel	49	Summer Capacity = 40 MW
Borden	1	Diesel	14	Summer Capacity = 12 MW
	2	Diesel	25	Summer Capacity = 20 MW
Summerside Diesels	1	Diesel	2	Owned by the City of Summerside
	2	Diesel	2	Owned by the City of Summerside
	3	Diesel	2	Owned by the City of Summerside
	5	Diesel	2	Owned by the City of Summerside
	6	Diesel	1	Owned by the City of Summerside
	7	Diesel	1	Owned by the City of Summerside
	8	Diesel	4	Owned by the City of Summerside
PEI Wind	All	Wind	75	During Maritime peak (204 MW installed)
TOTAL CAPACITY			225	Total Capacity as of January 2020

Table A-2 Maritimes Area Resources (cont'd)

Northern Maine Resources as of January 1, 2020				
Plant	**Unit**	**Type**	**MW Capacity**	**Notes**
Tinker		Hydro	35	
Ashland		Wood	0	37 MW mothballed January 1 2019
Caribou		Hydro	1	
		Diesel	8	
Squa Pan		Hydro	1	
EMEC		Oil/Hydro	20	
NMISA Wind	All	Wind	11	During Maritime peak (42 MW installed)
TOTAL CAPACITY			76	Total Capacity as of January 2020

Table A-3: Summary of Changes in Modeled Capacity

Month/ Year	Capacity Change MW	Capacity Balance MW	Explanation Total Capacity includes installed capacity, tie benefits, firm purchases and/or sales, and planned maintenance
Jan. 1, 2020	0	6,927	Starting Capacity
	+109	7,036	109 MW Hydro unit returned back to service after maintenance starting February.
	+5	7,041	5 MW added mid 2020 due to difference between 153 MW firm purchase offsetting 148 MW retirement
	+110/-69	7,082	Removal of 110 MW sale after May, Addition of 69 MW sale starting June
	-10	7,072	10 MW oil generator retired Jan 1
Jan. 1, 2021	+6	7,078	20 MW of wind de-rated to 6 MW on peak added January 1
	+6	7,084	20 MW of wind de-rated to 6 MW on peak added June 1
	+3	7,087	Removal of 69 MW sale after May, Addition of 66 MW sale starting June
	-38	7,049	38 MW from 2 * 19 MW oil generators retired Jan 1
Jan. 1, 2022	+6	7,055	20 MW of wind de-rated to 6 MW on peak added January 1
	+18	7,073	18 MW diesel added December 1
Jan. 1, 2023	+66/-149	6,990	Removal of 66 MW sale after May, Addition of 149 MW sale starting June
	+149	7,139	Removal of 149 MW sale after May
Jan. 1, 2024	0	7,139	No changes

2.2 Generator Unavailability Factors

2.2.1 Types of Unavailability Factors Represented

The types of unavailability factors represented in this reliability assessment are forced outages and planned outages. Forced outages include unplanned maintenance outages, deferrable forced outages, starting failure outages and generator derating adjustments. All except planned outages are included in the Forced Outage Rates (FORs) presented in Table A-4. Planned outages are scheduled manually for the reliability program based upon projected maintenance schedules.

New Brunswick forced outage rates are three year calculations using the Derating Adjusted Forced Outage Rate (DAFOR) methodology in IEEE Standard 762-2006, Section 8.17.4.

NSPI also uses three year average DAFOR calculations for forced outage rates consistent with IEEE Standard 762-2006, Section 8.17.4. NSPI maintains a database of combustion turbine and fossil generator reliability and performance data and is a contributing utility to the Canadian Electricity Association Equipment Reliability Information System (CEA-ERIS). The CEA-ERIS also calculates DAFOR using the industry standard definition as per IEEE 762-2006.

The forced outage rates for the smaller PEI and Northern Maine systems are modeled using forced outage rates for generators of similar size and fuel type in New Brunswick and Nova Scotia. Most of the small diesel and oil fueled generators in these systems operate less than 100 hours per year, and statistics necessary for calculating their DAFOR values are not available. The modeled FOR values for generators in these systems are between 5 – 10 %.

2.2.2 Source of Unavailability Factors

Forced Outage Rates for existing generators are based on actual outage data as well as on data of similar sized generators as compiled by the Canadian Electricity Association (CEA).

FORs for new generators are based upon the utilities' experience with similar generators in conjunction with averages compiled by the Canadian Electricity Association (CEA).

2.2.3 Maturity Considerations

Immature FORs were not used in this evaluation.

2.2.4 Tabulation of Forced Outage Rates

The ranges of FORs used in the assessment are tabulated in Table A-4. These values are consistent with those used in the business plans of the Maritimes Area utilities and reflect the results of maintenance and operational strategies.

Table A-4: Maritimes Area Forced Outage Rates

Unit Type	3 year DAFOR Forced Outage Rates (weighted)	
	2019 Review	2016 Review
Oil	4%	3%
Coal	3%	3%
Hydro	3%	1%
Nuclear	4%	7%
Natural Gas	3%	3%
Wind	0%	0%
Oil/Gas	16%*	6%
Biomass	2%	6%

*A single gas/oil unit experienced a FOR of 36% during the FOR calculation period of 2015 to 2018 that set a high value for that unit for this CRRA review.

2.3 Purchase and Sale Representation

External purchases and sales are represented as positive or negative adjustments to the Maritimes Area capacity respectively.

2.4 Retirements

Retirements were considered by removing the generators from the model at their retirement date. The largest known retirement assumed during the 2020 to 2024 period of this review is the planned mid-2020 retirement of the 148 MW Lingan 2 generator in Nova Scotia. Reliability impacts for this retirement will be negligible as the retirement is to be simultaneously offset by a similar sized hydro based firm capacity purchase. Several smaller units (the largest being 37 MW) totaling 175 MW were assumed retired or mothballed during the 2020 to 2024 period of this review. These smaller retirements reduced reserves but the LOLE analysis still confirmed that both the 20% reserve target and the 0.1 days/ year probabilistic target are for all years met within the Maritimes Area even under the stressed sensitivity analyses described herein.

3.0 Representation of Interconnected Systems

Since 2011, NB Power has assumed 300 MW of tie benefits to New Brunswick in its resource adequacy assessments. These tie benefits are based on a 2011 decision by the New Brunswick Market Advisory Committee to recognize the lowest historical Firm Transmission Capacity posted from summer peaking New England to winter peaking New Brunswick since the commissioning of the second 345 kV tie between these systems in December 2007. To the extent that future capacity purchases from New England to New Brunswick occur across this interface, these tie benefits will be reduced accordingly. Tie benefits from other neighbouring jurisdictions that are also winter peaking are not considered.

In the CP-8 report Review of Interconnection Assistance Reliability Benefits (December 31, 2015, Approved by RCC March 2, 2016) the "As Is" estimated tie benefit potential for the Maritimes Area is 702 MW to 1,012 MW for the years 2016 and 2020 with an export of 200 MW modeled in both test years. Based on this study, the 300 MW of tie benefits assumed for this 2019 Comprehensive Review is conservative.

4.0 Modeling of Variable and Limited Energy Sources

Wind resources are modeled as simulated hourly values that are netted out against the hourly loads. The hourly wind shape for any Maritimes Area jurisdiction is based upon each jurisdiction's hourly wind production during the 2017 calendar year expressed as a percentage of the jurisdiction's total installed wind for the hour. Any new wind capacity forecast for a jurisdiction is modeled this same historical hourly wind shape.

Under normal operating conditions, the hydro system is operated considerably below its DMNC rating due to economics. However, if required to maintain customer load, it would be operating at full capacity by utilizing the headponds and other existing storage reservoirs. This is one of the options documented in the Emergency Operating Procedures (Section 2.2 of the main report). Therefore, in the evaluation, hydro generators are considered available for all hours during which the generator is not on forced outage or maintenance. There are no seasonal adjustments to the DMNC ratings of the hydro generators.

5.0 Modeling of Demand Side Management

The expected monthly demand and energy reduction due to Demand Side Management programs for each sub-area is included in their respective forecasts and in the combined Maritimes Area forecast in Table A-1.

6.0 Modeling of Non-Utility Generation

Certain small non-utility generators are aggregated into single units with operating characteristics and FORs equivalent to other Maritimes Area generators of similar size. These are tabulated in Table A-2 and are identified by type NUG. In addition to these NUG units, a Nova Scotia's Community Fit (COMFIT) program generators are also non-utility generators.

7.0 Other Assumptions

The study assumed that there would be no generator slippages or deratings due to environmental constraints within the five-year timeframe of this review.

In NB, current emission limits are specified as annual system volumes rather than generator specific volumes, providing flexibility in the operation of the fleet.

Current regulations limiting greenhouse gas emissions and air pollutants are in place for the 2020-2030 timeframe in Nova Scotia specify multi-year hard caps rather than annual limits which provide for some flexibility in the operation of the fleet over the specified compliance periods. System Operators in the Maritimes Area will be tracking such standards as they are implemented and may conduct analyses in the future regarding their impact on resource adequacy.

APPENDIX B - DESCRIPTION OF RELIABILITY PROGRAM

DESCRIPTION OF RELIABILITY PROGRAM

The program used for this assessment, LOLP, was originally developed at NB Power in 1984 to complete the Triennial Review of Resource Adequacy. Since that time the program has been improved, and its capabilities expanded, with the most recent modifications being completed during the winter of 2018/19.

The original program was a single area program that performed the classical Loss of Load Probability (LOLP) analysis based upon the weekday peak hour load, as well as an Loss of Load Hours (LOLH) and Expected Energy Not Served (EENS) analysis which is based upon all of the hourly loads. The results of the program were benchmarked against the results of the IEEE reliability test system, as well as against the results of the PICES program used by NSPI for the 1991 Triennial Review. The program was further benchmarked by evaluating its results against those documented in the 1992 CIGRE Task Force 38-03-10 report “Composite Power System Reliability Analysis Application to the New Brunswick Power Corporation System"”. In all cases, excellent agreement of results was observed.

In the fall of 2007, modifications to the original program allowed it to perform a Monte Carlo analysis of a multi-area system with intra-area tie limits. This Monte Carlo simulation was written using MATLAB® software for programming and random number generation, and it performs as follows:

- For each daily coincident peak load, generation is simulated in each jurisdiction of the Maritimes. In the case of wind generation, hourly wind generation projections for the time of the Area coincident peak are netted against the loads. This simulation uses random numbers against a generator’s Forced Outage Rate to determine the status of each generator. Planned generator maintenance is also enforced.
- Generation surpluses or deficits are determined for each intra-area jurisdiction. Because each jurisdiction other than New Brunswick (NB) is only connected to NB, these surpluses and deficits can be transferred to New Brunswick.
- Surpluses transferred to NB from another intra-area jurisdiction are limited by the export limit of the jurisdiction.
- Deficits in an intra-area jurisdiction other than NB that exceed the import capability from NB results in a loss of load event. Otherwise, the deficit is transferred to NB. If more than one sub-area experiences a loss of load contingency on the same day, it is included as a single loss of load event for the Maritimes area as a whole.
- With all transfer-limited intra-area surpluses and deficits transferred to NB, it is determined whether or not the simulated generation in NB plus transferred surpluses is adequate to supply both the NB load and any transferred deficits. If not, then a loss of load event occurs.
- The Monte Carlo simulation is performed for each daily peak hour of the year, and the yearly simulation is repeated 100,000 times to calculate the average LOLE in days/year.

The base load shape for the program is system hourly net loads for each jurisdiction comprising the Area. Monthly load shapes for the individual jurisdictions are created by scaling the hourly loads to match the load forecast values of both demand and energy. This method preserves the effects of load chronology as well as load coincidence between the jurisdictions. This method is also identical between the new program and the old program. A separate monthly load shape comprising only the peak load of each day is created for the LOLE analysis.